# TECHNICAL REVIEW DOCUMENT for OPERATING PERMIT 010PMR236

to be issued to:

Manchief Power Company, LLC – Manchief Generating Station
Morgan County
Source ID 0870011

Prepared by Jacqueline Joyce
November and December 2002
Revised February, May and October 2003
Revised November 4, 2003 based on comments made by EPA during the EPA 45-day review period

#### I. Purpose:

This document establishes the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA, the Public and other interested parties. Conclusions made in this report are based on information provided by the applicant in the Title V application submitted July 9, 2001, a revised application submitted on February 7, 2003, additional information received on October 17, 2003, comments on the draft operating permit and technical review document received on February 7 and May 7, 2003, various telephone conversations and e-mail correspondence with the source and review of Division files. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised Construction Permit.

## II. Source Description:

The Manchief Generating Station consists of two natural gas-fired simple cycle combustion turbines used to generate electric power and is defined under Standard Industrial Classification 4911. Each turbine is rated at a heat input of 1,279 mmBtu/hr and drives a generator rated at 142 MW at 32° F. Each turbine is equipped with an advanced dry low NO<sub>X</sub> (DLN) combustion system to minimize NO<sub>X</sub> emissions. Commercial operation of the units commenced in July 2000. In addition to the combustion turbines this facility also has a diesel fired internal combustion engine that

drives a 3 MW generator. The generator is used to start the combustion turbines and is occasionally used to supplement peak power needs. In addition, a natural gas-fired indirect water bath heater is used to pre-heat the natural gas delivered to the turbines.

The facility is located at 14936 County Road 24, approximately 4.2 miles south of Brush in Morgan County. The Manchief Generating Station is located adjacent to Public Service Company's Pawnee Generating Station.

The initial approval construction permit and subsequent modifications to that permit issued for the Manchief Generating Station were processed considering that the Manchief and Pawnee Generating Stations were separate sources. During the Public Comment period for the Title V operating permit, the EPA indicated that the single vs. separate source issue for the Manchief and Pawnee Generating Stations should be reviewed. The Division, EPA and Manchief Power Company, LLC have all agreed that based on the power purchase agreements in place at this time, that the Manchief and Pawnee Generating Stations are a single source for purposes of Title V, MACT and PSD. Since the Pawnee Generating Station is a listed source (fossil fuel-fired steam electric plants of more than 250 mmBtu/hr), the PSD threshold level for the single source of the Pawnee and Manchief Generating Stations is 100 tons/yr. Note that the Manchief Title V operating permit is one of three issued for this particular source. In addition to the Manchief permit, there is a Title V operating permit (96OPMR129) issued to Public Service Company for the Pawnee Generating Station and a Title V operating permit (03OPMR244) issued to Boral Material Technologies, Inc for their ash handling operations at the Pawnee Generating Station.

This facility is considered to be a major stationary source (Potential to Emit > 100 tons/year) in an attainment area and has a PSD permit. Future modifications to this facility which are in excess of significance levels as defined in Colorado Regulation No. 3, Part A, Section I.B.58, would result in a major modification and the application of PSD requirements. Facility wide emissions are as follows:

Pollutant	Potential to Emit (tons/yr)				Actual Emissions (tons/yr)			
	PSCo	BMTI	Manchief	Facility	PSCo	BMTI	Manchief	Facility
PM	2,501.7	22.93	132.4	2,657.03	724.2	22.93	58.07	805.2
PM <sub>10</sub>	2,231.6	8.91	97.2	2,337.71	638.8	8.91	42.64	690.35
NO <sub>X</sub>	11,765	N/A	812.7	12,577.7	4,893.4	N/A	275.85	5,169.25
SO <sub>2</sub>	28,176.9	N/A	7	28,183.9	14,677.9	N/A	3.1	14,681
CO	754.7	N/A	310.7	1,065.4	582.6	N/A	58.47	641.07
VOC	91.5	N/A	43.8	135.3	72.2	N/A	20.27	92.47
HAPS	143.6	Negl.	11.4	155	24.8	Negl.	Negl.	24.8

Potential to emit and actual emissions for PSCo are the same values included in the technical review document to support the original Title V permit operating permit (issued January 1, 2003). Potential to emit for BMTI and Manchief are based on permitted emissions. For Manchief, the potential to emit of HAP emissions are based on information submitted in June 1999 to support the original construction permit application. BMTI reported potential emissions as actual emissions on the most recent APEN, which is an acceptable practice. For Manchief, actual emissions are based on

the information provided in the annual report submitted on May 2, 2002 for calendar year 2001. It should be noted that the Title V operating permit issued to PSCo for Pawnee Station includes conditions for processing fly ash through the ash silo and depositing fly ash at the ash pit. Generally, processing of most of the fly ash at Pawnee Station is done by BMTI. Therefore, emissions from ash handling are "double counted" in that they are included in the PTE analysis and the operating permit for PSCo and also for BMTI.

There are no Federal Class I designated areas within 100 kilometers and no affected states within 50 miles of this facility.

This facility certified within the Title V permit application they are not subject to 112(r), the Accidental Release Requirements.

CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. The diesel generator and gas pre-heater are not equipped with any control devices.  $NO_X$  emissions from the turbines are controlled by DLN combustion systems. DLN combustion systems are not considered control devices as defined in 40 CFR Part 64 §64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since DLN combustion systems are considered inherent process equipment. Therefore, the CAM requirements do not apply to the turbines at this facility.

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the "MACT hammer".

Owner or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline were required to submit a Part 1 application to revise this operating permit by May 15, 2002. Manchief station has equipment for three covered source categories (combustion turbines, reciprocating internal combustion engines and industrial, commercial and institutional boilers and process heaters). submitted a part I application by the May 15, 2002 deadline but did not indicate whether or not they are a major source for HAPS. In the cover letter for the Part 1 application, the source indicated that based on preliminary estimates of potential to emit that they are not a major source. However, they requested that the Division conduct an applicability determination. As discussed previously, the single vs. separate source determination for the Pawnee and Manchief Generating Stations was reviewed and the Division now considers that Pawnee and Manchief are a single source and because of that determination, the Manchief Generating Station is a major source of HAPs.

The final rule for combustion turbines was signed on August 29, 2003. The final rule exempts existing combustion turbines (commenced construction on or before January

14, 2003) from the MACT standards. Proposed rules for reciprocating internal combustion engines and commercial and institutional boilers and process heaters have been published. The proposed rule for the commercial and institutional boilers and process heaters does not appear to exempt any units based on size (i.e. exempt small units) but does not appear to include any requirements for existing units in the small gaseous fuel subcategory (unit rated at less than 10 mmBtu/hr). Therefore, at this time it appears that the gas heater will not be subject to any substantive requirements. In addition, the engine at this facility is limited to 400 hrs/yr of operation. The proposed rule for reciprocating internal combustion engines exempts limited use engines from the standards. However, the proposed rule defines limited use as 50 hrs/yr. Therefore, based on the proposed rule, the engine could potentially be subject to substantive applicable requirements.

#### **III.** Emission Sources:

The following sources are specifically regulated under terms and conditions of the Operating Permit for this Site:

<u>Units S001 and S002</u> - Two (2) Siemens Westinghouse Model V84.3A1 Natural Gas Fired Combustion Turbines, Each Rated at 1,279 mmBtu/hr, Serial Numbers: 800310 (CT001) and 800311 (CT002). Each Turbine Drives a Generator Rated at 142 MW at 32° F. Each Turbine is Equipped with Dry Low  $NO_X$  Combustion Systems to Minimize  $NO_X$  Emissions.

#### Discussion:

1. Applicable Requirements - These units were issued Colorado Construction Permit 99MR0169 PSD (initial approval) on August 23, 1999. The construction permit was revised on May 23, 2000 to add provisions for a diesel fired engine powering a generator to start-up the turbines and a natural gas fired heater to heat the natural gas before it is fed to the turbines. The turbines commenced commercial operation in July 2000. In August 2001, the source requested revisions to the construction permit to provide an alternate BACT limit for periods of startup and shutdown. A revised construction permit (initial approval, modification 2) was issued August 23, 2002.

The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the initial approval construction permit (99MR0169 PSD, issued August 23, 2002) was issued and/or the equipment commenced operation. Therefore, under the provisions of Regulation No. 3, Section V.A.2, the Division is allowing the initial approval construction permit to continue in full force and effect and will consider the Responsible Official certification submitted with that report to serve as the demonstration required pursuant to Regulation No. 3, Part B, Section IV.H and no final approval construction permit will be issued. The appropriate provisions of the initial approval construction permit have been directly incorporated into this operating permit.

The following applicable requirements from construction permit 99MR0169 PSD (initial approval, modification 2, dated August 23, 2002) have been identified for these units:

 Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (condition 2 and Colorado Regulation No. 1, Sections II.a.1 & 4).

Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term "normal operations" applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered "normal operation". Therefore, the language in the permit will not specify "normal operation". The 30% opacity requirement will be written to include all the specific operational activities identified in Reg 1.

 This source is subject to the requirements of Prevention of Significant Deterioration (PSD). Best Available Control Technology (BACT) shall be applied for control of Oxides of Nitrogen (NO<sub>X</sub>), Carbon Monoxide (CO), Particulate Matter (PM and PM<sub>10</sub>) and Volatile Organic Compounds (VOC) (condition 3).

#### NO<sub>X</sub>:

DLN combustion systems have been determined to be BACT for these turbines.

Hourly average concentration of  $NO_X$  in the turbine exhausts shall not exceed the following limits (per turbine):

- o Except as provided for below,  $NO_X$  emissions shall not exceed 15 ppmvd at 15%  $O_2$
- o During periods of startup and shutdown, NO<sub>X</sub> emissions shall not exceed 100 ppmvd at 15% O<sub>2</sub>
- o During low load operations between March 1 through October 31, NO<sub>X</sub> emissions shall not exceed 25 ppmvd at 15% O<sub>2</sub>
- o "Startup" means the setting in operation of any air pollution source for any purpose. Setting in operation for these turbines begins with the initial fuel firing to the combustion turbine. Setting in operation for these turbines ends at the end of the clock hour following the clock hour during which the turbine has been in the premix mode for 20 minutes. Premix mode starts when the pilot gas valve opens and the diffusion valve closes.
- o "Shutdown" means the cessation of operation of any air pollution source for any purpose. The cessation of operation for these turbines begins when the command signal is initiated by the turbine operator to shutdown the unit and ends when fuel is no longer being fired in the turbine.
- "Low load operation" is defined as individual turbine operation less than or equal to 100 MW (approximately 70% of the base load operation at 142 MW at 32° F).

#### CO:

Good combustion practices shall be used to limit the CO emissions. "Good Combustion Practices" constitute monitoring and control of several operating parameters. These parameters include, but are not limited to, fuel flow rate, primary and secondary air flows, CO concentration in the flue gas and level of excess air. All relevant parameters and their optimal operating ranges are to be identified, and included in the operation and maintenance plan.

Hourly average concentration of CO in the turbine exhausts shall not exceed the following limits (per turbine):

- o Except as provided for below, CO emissions shall not exceed 10 ppmvd at  $15\% O_2$
- o During periods of startup and shutdown, emissions of CO shall not exceed 300 ppmvd at 15%  $\rm O_2$
- During low load operations between March 1 through October 31, CO emissions shall not exceed 15 ppmvd at 15% O<sub>2</sub>
- o "Startup", "shutdown" and "low load operation" shall have the same definitions as indicated under NO<sub>X</sub> above.

#### VOC:

Use of pipeline quality natural gas and application of "good combustion practices" to minimize emissions of volatile organic compounds, is determined as BACT. Concentration of volatile organic compounds shall not exceed 3 ppmvd at 15%  $O_2$  (per turbine). Detail of "good combustion practices" must be included in the operation and maintenance plan.

#### PM and PM<sub>10</sub>:

Use of pipeline quality natural gas and application of "good combustion practices" to minimize formation of particulate matter, both filterable and condensable, is determined to be BACT. Detail of "good combustion practices" must be included in the operation and maintenance plan.

- For each combustion turbine, continuous emission monitoring systems (CEMS) shall be installed, calibrated and operated to determine and record (condition 4):
  - o Concentration of NO<sub>X</sub>, ppmvd hourly average, on the exhaust
  - o Emissions of NO<sub>X</sub>, tons/month<sup>1</sup>
  - o Concentration of CO, ppmvd hourly average, on the exhaust
  - o Emissions of CO, tons/month<sup>1</sup>
  - o Concentration of O<sub>2</sub>, percent hourly average, on the exhaust
  - o Operating mode startup, shutdown, low load operation and/or standard operation<sup>2</sup>
  - o Load, in MW, at which turbine is operating

<sup>1</sup>Monthly emissions from the CEMS shall be used in twelve month rolling totals to monitor compliance with the annual emission limitations.

<sup>2</sup>Note that the CEMS does not currently record operating mode, however, the permittee is in the process of modifying the CEMS to indicate this information. Therefore, until the CEMS records this information the permittee shall maintain records to indicate the dates and times that the units are running in modes other than standard operation.

The source has indicated that the CEMS has been modified to record the operating mode, so the second footnote will not be included in the operating permit.

- The following applies to the CEMS for each turbine (condition 4):
  - o Except where noted below, the NO<sub>X</sub> and diluent (either O<sub>2</sub> or CO<sub>2</sub>) CEMS shall meet the applicable requirement in 40 CFR Part 75, the performance specification requirements in 40 CFR Part 75 Appendix A and QA/QC requirements in 40 CFR Part 75 Appendix B. In regards to specific QA/QC tests, for the daily calibrations the NO<sub>X</sub> CEMS shall meet the 5% error standard (not the 10 ppm error for spans less than 200 ppm) and for the quarterly linearity checks the NO<sub>X</sub> CEMS shall meet the 5% error standard (not the 5 ppm standard).
  - Except where noted below, the CO CEMS shall meet the applicable requirements in 40 CFR Part 60 Subpart A § 60.13, the performance specification requirements in 40 CFR Part 60 Appendix A and the QA/QC requirements in 40 CFR Part 60 Appendix F.
  - NO<sub>X</sub> and CO CEMS data shall meet the applicable "primary equipment hourly operating requirements" for hourly average calculation methodology specified in 40 CFR Part 75 Subpart B § 75.10(d).
  - Quality assured data shall be available for a minimum of 90 percent of the periods of operation of the turbines.
    - The construction permit specifies that the continuous monitoring systems meet the requirements in 40 CFR Part 75 (NO $_{\rm X}$  and diluent monitoring systems and in 40 CFR Part 60 Subpart A § 60.13 (CO monitoring system). The requirement to provide quality assured data for 90% of the duration of the operation conflicts with the requirements in 40 CFR Part 75 § 75.10(d) and Part 60 § 60.13(e), which require that the continuous monitoring systems be operated at all times, except under certain conditions. Therefore, it was not appropriate for the Division to include the 90% requirement in the construction permit. This requirement will not be included in the operating permit.
  - Written notification of monitoring system demonstrations shall be submitted to the Division as required in accordance with the provisions of 40 CFR Part 60 Subpart A § 60.7 for all CEMS.
  - o Excess emission reports shall be submitted to the Division on a quarterly basis. The content of the excess emission reports shall meet the requirements provided in 40 CFR Part 60 Subpart A § 60.7.

- o When quality-assured data is not available, compliance with the  $NO_X$  and CO emission limitations in Condition 13 shall be monitored using the missing data procedures in 40 CFR Part 75 Subpart D.
- The CEMS shall be used to determine compliance with emission limits for NO<sub>X</sub> and CO.
- The turbines shall be equipped with in-line fuel flow meters that meet the applicable requirements in 40 CFR Part 75 Appendix D to measure the fuel combusted in each turbine. Fuel flow data shall be recorded on a data acquisition and handling system as specified in 40 CFR Part 75 Appendix D (condition 5).
- Preconstruction monitoring and analysis and post-construction monitoring for ozone is not applicable as per the provision in Regulation No. 3, Part B, Section IV.D.3.b.(iii).(C), as long as the emissions of VOC are less than 100 tons per twelve-month rolling period. If emissions reach this limit, operation of both these turbines shall be suspended, and the operation may be resumed only after fulfilling the requirements specified in Regulation NO. 3, part B, Section IV (condition 6).

The turbines are not permitted to operate at levels above 100 ton/yr of VOC and stack testing has indicated that levels of VOC are lower than manufacturers' data has indicated. Therefore, this is not an applicable requirement and it will not be included in the operating permit.

- The turbines are subject to Regulation No. 6 Standards of Performance for New Stationary Sources, Part A - Federal Register Regulations Adopted by Reference, Subpart GG - Standards of Performance for Stationary Gas Turbines (condition 7):
  - o  $NO_X \le 114$  ppmvd at 15% oxygen. (Compliance with the BACT limits will satisfy this NSPS standard).
  - o  $SO_2 \le 150$  ppmvd at 15% oxygen **OR** sulfur content in the fuel shall not exceed 0.8 percent by weight.
  - Sulfur and nitrogen content of the fuel being fired in the turbines shall be monitored as specified in this Subpart GG, or by custom monitoring schedule approved by EPA.

EPA approved a custom monitoring schedule for these units on July 10, 2002 (see attached). The approved schedule requires no sampling for nitrogen content since natural gas is used as fuel and requires that sulfur content sampling be conducted as required by 40 CFR Part 75 Appendix D.

Although not specifically included in the construction permit, the following requirements also apply:

- o Excess emissions reporting requirements (§ 60.334(c))
- o Performance test requirements, regarding fuel sampling (§§ 60.335(d)

- The turbines are also subject to the requirements in 40 CFR Part 60 Subpart A – New Source Performance Standards – General Provisions, as adopted by reference in Colorado Regulation No. 6, Part A, the following will be included in the permit (condition 7):
  - o Good practices (§ 60.11(d))
  - o Circumvention (§ 60.12)

Note that a more extensive list of requirements from 40 CFR Part 60 Subpart A was included in the construction permit. However, these requirements, if still applicable, will be included in the permit as periodic monitoring or under the continuous emission monitoring requirements and will not be specifically identified as requirements under the NSPS general provisions.

- The source is subject to Regulation No. 6 Standards of Performance for New Stationary Sources, Part B – Specific Facilities and Sources, Non-Federal NSPS, II – Standards of Performance for New Fuel-Burning Equipment, D – Standard for Sulfur Dioxide, 3 – Combustion Turbines (condition 9). These are state-only requirements.
  - o SO<sub>2</sub> emissions shall not exceed 0.35 lbs/mmBtu.

Although not specifically identified in the construction permit, the turbines are also subject to the 20% opacity requirement in Section II.C.3.

• This source is subject to the odor requirements of Regulation No. 2 (condition 8)

Turbines are not generally a source of odor therefore this condition will not be specifically included in the permit but is included in the General Conditions (Section V) of the permit.

- An annual report shall be submitted to the Division, by April 30, for the previous calendar year. This report shall contain, at a minimum, the following (condition 11):
  - o Consumption of natural gas
  - o Total emissions of all pollutants as determined by the CEMS (for NO<sub>X</sub> and CO) and alternate methodology (for all other pollutants)
  - o Episodes of emission exceedances
  - o Certification of compliance/non-compliance of permit conditions
  - o Upset conditions and remedial measures taken

With the issuance of the operating permit the source will be required to certify

annually that they are in compliance with the conditions in the operating permit, which includes compliance with the emission limitations, fuel consumption limits and reporting requirements (including APEN reporting and excess emission reports). The majority of the information that the source is required to include in this annual report is already required to be reported under APEN (fuel consumption and annual emissions) and excess emission reporting requirements. Therefore, this requirement will not be included in the operating permit.

- This source shall be limited to a maximum consumption rate as listed below and all other activities, operation rates and numbers of equipment as stated in the application. Monthly records of the actual throughput shall be maintained by the permittee and made available to the Division for inspection upon request (condition 12).
  - Consumption of natural gas for combustion in each turbine shall not exceed 11,925 mmSCF/yr.
- Emissions of air pollutants from each shall not exceed the following limitations (condition 13):

Pollutant	Emission limit, tons		
	Rolling 12 months		
Particulate Matter	66.20		
Particulate Matter < 10 μm [PM-10] (includes condensables)	48.60		
Oxides of Nitrogen	396.70		
Carbon Monoxide	153.70		
Volatile Organic Compounds	21.90		
Sulfur Dioxide	3.50		

APEN reporting (condition 14 and Colorado Regulation No. 3, Part A Section II.C)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

Although not specifically identified in Colorado Construction Permit 99MR0169 PSD, the turbines are subject to the following applicable requirements:

 Particulate matter emissions, from each turbine, shall not exceed 0.1 lbs/mmBtu (Reg 1, Section III.A.1.c)

- Sulfur dioxide emissions, from each turbine, shall not exceed 0.35 lbs/mmBtu, on a 3-hour rolling average (Reg 1, Section VI.B.4.c.(ii) and VI.B.2)
- Each turbine is subject to the Acid Rain requirements as follows:
  - o Allocated SO<sub>2</sub> allowances are listed in 40 CFR Part 73.10(b), however, since these are new units, no allowances were allocated. SO<sub>2</sub> allowances must be obtained per 40 CFR Part 73 to cover SO<sub>2</sub> emissions for the particular calendar year.
  - o There are no NO<sub>X</sub> emission limitations since these units are not coalfired boilers.
  - o Acid rain permitting requirements per 40 CFR Part 72.
  - o Continuous emission monitoring requirements per 40 CFR Part 75.
  - o This source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

## **Streamlining of Applicable Requirements**

## **Opacity**

The turbines are subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operational activities. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. The turbines are also subject to the state-only Reg 6, Part B 20% opacity requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Therefore, since no one opacity requirement is more stringent than the other at all times, all three opacity requirements are included in the operating permit. See the attached grid for a clarified view on the opacity requirements and their relative stringency

It should be noted that since these turbines use natural gas as fuel, the Division will presume, in the absence of credible evidence to the contrary, that these units are in compliance with all of the opacity requirements.

# <u>SO</u><sub>2</sub>

The turbines are subject to the Regulation No. 1 and Regulation No. 6, Part B SO<sub>2</sub> requirements. The Regulation No. 1 and No. 6, Part B SO<sub>2</sub> standards are the same, 0.35 lbs/mmBtu. The Regulation No. 6, Part B requirement is a state-only requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has

concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported in the excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "...it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B SO<sub>2</sub> requirements do not apply during periods of startup, shutdown and malfunction. Therefore, the Regulation No. 1 SO<sub>2</sub> requirement is more stringent than the Regulation No. 6, Part B requirement and the Regulation No. 6, Part B requirements will be streamlined out of the permit.

The turbines are also subject to the Acid Rain  $SO_2$  requirements. Sources subject to Acid Rain must hold adequate  $SO_2$  allowances to cover annual emissions of  $SO_2$  (1 allowance = 1 ton per year of  $SO_2$ ) for a given unit in a given year. The number of allowances can increase or decrease for a unit depending on allowance availability. Allowances are obtained through EPA, other units operated by the utility or the allowance trading market and compliance information is submitted (electronically) to EPA. Pursuant to Regulation No. 3, Part C, Section V.C.1.b, if a federal requirement is more stringent than an Acid Rain requirement, both the Reg 1 and the Acid Rain  $SO_2$  requirements shall be incorporated into the permit and shall be federally enforceable. For these reasons, the Acid Rain  $SO_2$  requirements have not been streamlined out of the permit. The source will have to demonstrate compliance with both the Acid Rain  $SO_2$  requirements and the Reg 1  $SO_2$  standard. Note that the Acid Rain  $SO_2$  allowances appear only in Section III (Acid Rain Requirements) of the permit.

# $NO_X$

Since the NSPS Subpart GG and BACT concentration limits are in the same units, they can be compared for purposes of streamlining. The BACT concentration limits are applicable at all times. The Division considers that the NSPS Subpart GG requirements are not applicable during periods of startup, shutdown and malfunction (as discussed in the SO<sub>2</sub> streamlining section above). Therefore, since the NSPS Subpart GG limits are less stringent than the BACT concentration limits, the NSPS Subpart GG limits will be streamlined out of the operating permit.

Note that streamlined conditions are subsumed within the requirements identified in Section II of the permit. For purposes of compliance demonstration, compliance with the conditions in Section II of the permit also serve as compliance demonstration for the subsumed condition. Since the NSPS GG NO $_{\rm X}$  limit has been streamlined out in favor of the BACT NO $_{\rm X}$  limits, the source may wish to retain records of ambient temperature and humidity data which is used to convert NO $_{\rm X}$  values to ISO standard day conditions, in the event that the NO $_{\rm X}$  BACT limit is violated at such a level that compliance with the NSPS GG BACT limit is uncertain.

## Monitoring Requirements

NSPS Subpart GG requires daily sampling of fuel to determine the nitrogen and sulfur content of the fuel. In an August 14, 1987 memo, the EPA waived the fuel sampling requirements to determine the nitrogen content for pipeline quality natural gas. The source submitted a request to EPA to approve, as an alternative to the fuel sulfur content monitoring in NSPS Subpart GG to demonstrate that pipeline quality natural gas (as defined in 40 CFR Part 72) is used as fuel in accordance with the requirements in 40 CFR Part 75 Appendix D. EPA approved this request in a letter received on July 10, 2002. Therefore, the fuel sampling requirements in NSPS Subpart GG will be streamlined out of the permit in favor of the NO<sub>X</sub> CEMS (nitrogen content fuel sampling) and using pipeline quality natural gas as fuel (sulfur content fuel sampling).

**2. Emission Factors-** Emissions from these turbines are produced during the combustion process, and are dependent upon operating conditions and specific properties of the natural gas being burned. The pollutants of concern are Nitrogen Oxides ( $NO_X$ ), Carbon Monoxide (CO), Volatile Organic Compounds (VOC) and Particulate Matter (PM and  $PM_{10}$ ). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted dependent upon the makeup of the fuel and combustion efficiency.

The emission factors that will be used to monitor compliance with the emission limits are as follows:

Pollutant	Emission Factor	
РМ	Unit 1 – 10.5 lbs/mmSCF Unit 2 – 7.8 lbs/mmSCF	
PM <sub>10</sub>	Unit 1 – 5.8 lbs/mmSCF Unit 2 – 7.6 lbs/mmSCF	
SO <sub>2</sub>	CMS	
NO <sub>X</sub>	CEMS	
СО	CEMS	
VOC	3.7 lbs/mmSCF	

The PM and  $PM_{10}$  emission factors for Unit 2 are from performance tests conducted on this unit on September 8 and 11, 2000. The PM and  $PM_{10}$  emission factors for Unit 1 are from performance tests conducted on this unit on December 10, 2002. It should be noted that the Division has not approved the December 10, 2002 test yet and that the Division may require further testing to approve the test. In addition, if based on the Division's review of the test, the Division indicates that a different emission factor is appropriate, the permit will be revised as necessary prior to permit issuance or a permit reopening will be initiated if such a decision is made after issuance of the permit.

The VOC emission factor is from the construction permit and is based on manufacturer's estimates as indicated in the construction permit application submitted in June 1999. Stack tests conducted on September 7, 8 and 11, 2000 indicated that VOC emission levels are well below the emissions estimated by the manufacturer.

 $NO_X$  and CO emissions shall be determined using the continuous emission monitoring system required by the construction permit.  $SO_2$  emissions shall be determined using monitoring methods required by 40 CFR Part 75, Appendix D.

**3. Monitoring Plan-** The source shall be required to monitor compliance with the PM,  $PM_{10}$  and VOC emission limits by monitoring fuel consumption and calculating emissions monthly.

The continuous emission monitoring systems shall be used to monitor compliance with the BACT and annual  $NO_X$  and CO emission limitations. The monitoring methods required by 40 CFR Part 75, Appendix D shall be used to monitor compliance with the  $SO_2$  emission limitations.

Since the performance testing conducted for the turbines indicated that the VOC emissions from the turbines were much less than the 3 ppmvd BACT limit for these units (highest value was 0.3 ppmvd), the Division is not including any additional monitoring for the VOC BACT limit. In the absence of credible evidence to the contrary, compliance with the VOC BACT limit will be presumed provided pipeline quality natural gas is used as fuel and good combustion practices are applied.

In the absence of credible evidence to the contrary, compliance with the opacity, particulate matter and Reg 1 SO<sub>2</sub> limits shall be presumed provided natural gas is used as fuel.

**4. Compliance Status-** The source indicated in the Title V permit application that they were out of compliance with several conditions in their construction permit. Since submittal of the Title V operating permit application, a compliance order on consent was issued on July 1, 2002 and a revised construction permit was issued August 23, 2002. Therefore, the Division considers that the turbines are in compliance with all applicable requirements.

<u>Unit S003:</u> One (1) General Motors, No. 2 Diesel Fuel Fired Internal Combustion Engine, Model No. 20-045-E4, Serial No. 69-81-1097, Rated at 25.29 mmBtu/hr and 3600 HP. This Engine Drives a Generator Rated at 3 MW. Power from this Engine is Used to Start the Turbines.

#### Discussion:

1. Applicable Requirements- The diesel generator is included with the turbines and the gas heater on Colorado Construction permit 99MR0169 PSD. Colorado Construction Permit 99MR0169 PSD was first issued (initial approval) on August 23, 1999 and later revised (May 23, 2000) to add provisions for a diesel fired engine powering a generator to start-up the turbines and a natural gas fired heater to heat the natural gas before it is fed to the turbines. The turbines commenced commercial operation in July 2000. A revised construction permit (initial approval, modification 2)

was issued August 23, 2002 to address BACT limits for the turbines. As discussed under the turbines, the responsible official certification submitted with the first semi-annual monitoring report, will serve as the indication that the diesel generator can comply with the applicable requirements.

The following applicable requirements from construction permit 99MR0169 PSD (initial approval, modification 2, dated August 23, 2002) have been identified for this unit:

- This source is subject to the requirements of Prevention of Significant Deterioration (PSD). Best Available Control Technology (BACT) shall be applied for control of Oxides of Nitrogen (NO<sub>X</sub>). Retarded-time ignition and aftercooler have been determined to be BACT for the generator engine. Operation of the engine is limited to 400 hours per year (condition 3.a).
- Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (condition 2 and Colorado Regulation No. 1, Sections II.a.1 & 4).

Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term "normal operations" applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered "normal operation". Therefore, the language in the permit will not specify "normal operation".

Note that the 30% opacity requirement applies under other specific operational activities rather than just startup, process modification and adjustment of control equipment. The Division considers that these other activities such as fire building, cleaning of fire boxes and soot blowing are not applicable to the diesel engine. In addition, this engine does not have a control device. Also, based on engineering judgment, it is not expected that process modifications would occur during operation of this unit or that such modifications would not last longer than 6 minutes. Therefore, the 30% opacity requirement will only be included for startup.

- This source shall be limited to a maximum consumption rate as listed below and all other activities, operation rates and numbers of equipment as stated in the application. Monthly records of the actual throughput shall be maintained by the permittee and made available to the Division for inspection upon request (condition 12).
  - o Consumption of diesel fuel No. 2 for combustion in the engine shall not exceed 72,000 gal/yr.
  - Operation of the engine shall not exceed a total of 400 hours per year.
     Note that the limitation on hours of operation was also identified in Condition 3.a of the construction permit under the BACT requirements.

The hours of operation limit will only be included in the operating permit in one location.

 Emissions of air pollutants from each shall not exceed the following limitations (condition 13):

NO<sub>X</sub> emissions shall not exceed 15.4 tons/yr

Note that the other pollutants at the permitted fuel consumption rate and hours of operation are below APEN de minimis and therefore were not included in the permit. However, emissions of these pollutants shall still be reported on any APENs submitted and are still subject to annual fees.

APEN reporting (condition 14 and Colorado Regulation No. 3, Part A Section II.C)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

Although not specifically identified in the construction permit, the gas heater is subject to the following applicable requirements:

Sulfur dioxide emissions shall not exceed 0.8 lbs/mmBtu (Reg 1, Section IV.B.4.b.(i))

The source indicated in their Title V permit application that the engine is subject to the fuel burning equipment requirements in Colorado Regulations No. 1 (particulate matter) and No. 6, Part B. These requirements have not been included in the operating permit because the Division does not consider internal combustion engines to meet the regulatory definition of fuel-burning equipment and the Division does not consider the combustion of No. 2 diesel fuel to be a significant source of lead emissions.

**2. Emission Factors-** Approval of emission factors is necessary to monitor compliance with the emission limitations. The  $NO_X$  emission limit in the construction permit was set using a manufacturer's emission factor of 9.7 g/hp-hr. The manufacturer's emission factor was converted to units of lbs/mmBtu using the following equation:

EF (lbs/mmBtu) = 
$$\frac{\text{EF (g/hp-hr) x (10}^6 \text{ Btu/mmBtu)}}{\text{Heat rate (Btu/hp-hr) x (453.6 g/lb)}}$$

The Title V permit application indicated that engine had a design heat rate of 7,025 Btu/hp-hr. The converted emission factor that will be included in the operating permit is 3.04 lbs/mmBtu. It should be noted that the manufacturer's emission factor is less conservative than AP-42 (3.2 lbs/mmBtu from Section 3.4, Table 3.4-1, dated October 1996).

The APEN submitted March 27, 2000 with the application to revise the construction permit to add the diesel engine and gas heater, indicated that emissions from the diesel engine were based on manufacturer's emission factors and emissions from all pollutants except NO<sub>x</sub> were below APEN de minimis levels. Based on the permitted

fuel consumption rate, if AP-42 emission factors (Section 3.4, dated 10/96) had been used CO emissions would have exceeded APEN de minimis levels (~ 4 tons/yr of CO). However, since the engine is operated on a limited basis (400 hrs/yr) and emission estimates for CO using AP-42 are still quite low, the Division considers that use of the manufacturer's emission factor for CO is acceptable at this time.

- **3. Monitoring Plan-** The source shall be required to monitor fuel consumption and calculate emissions, from the generator, monthly. EPA Reference Method 9 observations shall be required to monitor compliance with the opacity requirements. In the absence of credible evidence to the contrary, compliance with the sulfur dioxide requirement is presumed provided the sulfur content of the diesel fuel does not exceed 0.5% by weight.
- **4. Compliance Status-** In their Title V permit application, the source indicated that the diesel engine was in compliance with all applicable requirements. The Division agrees with this assessment.

<u>Unit S004</u> – One (1) Gas Tech, Model Eclipse, Serial No. J-5419, Natural Gas Fired Indirect Water Bath Heater, Rated at 8.36 mmBtu/hr. This Heater is Used for Heating Fuel Gas Going to the Turbines.

#### Discussion:

1. Applicable Requirements- The gas heater is included with the turbines and the diesel engine on Colorado Construction permit 99MR0169 PSD. Colorado Construction Permit 99MR0169 PSD was first issued (initial approval) on August 23, 1999 and later revised (May 23, 2000) to add provisions for a diesel fired engine powering a generator to start-up the turbines and a natural gas fired heater to heat the natural gas before it is fed to the turbines. The turbines commenced commercial operation in July 2000. A revised construction permit (initial approval, modification 2) was issued August 23, 2002 to address BACT limits for the turbines. As discussed under the turbines, the responsible official certification submitted with the first semi-annual monitoring report, will serve as the indication that the gas heater can comply with the applicable requirements.

The following applicable requirements from construction permit 99MR0169 PSD (initial approval, modification 2, dated August 23, 2002) have been identified for this unit:

- This source is subject to the requirements of Prevention of Significant Deterioration (PSD). Best Available Control Technology (BACT) shall be applied for control of Oxides of Nitrogen (NO<sub>X</sub>). Low NO<sub>X</sub> burners have been determined to be BACT for the fuel gas heater (condition 3.a).
- Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (condition 2 and Colorado Regulation No. 1, Sections II.a.1 & 4).

Note that Colorado Regulation No. 1 does not identify the 20% opacity

requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term "normal operations" applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered "normal operation". Therefore, the language in the permit will not specify "normal operation".

Note that the 30% opacity requirement applies under other specific operational activities rather than just startup, process modification and adjustment of control equipment. The Division considers that these other activities such as fire building, cleaning of fire boxes and soot blowing are not applicable to the gas heater. In addition, this heater does not have a control device. Also, based on engineering judgment, it is not expected that process modifications would occur during operation of this unit or that such modifications would not last longer than 6 minutes. Therefore, the 30% opacity requirement will only be included for startup.

- This source shall be limited to a maximum consumption rate as listed below and all other activities, operation rates and numbers of equipment as stated in the application. Monthly records of the actual throughput shall be maintained by the permittee and made available to the Division for inspection upon request (condition 12).
  - o Consumption of natural gas for combustion in the heater shall not exceed 77.9 mmSCF/yr.
- Emissions of air pollutants from each shall not exceed the following limitations (condition 13):
  - o NO<sub>X</sub> emissions shall not exceed 3.9 tons/yr
  - o CO emissions shall not exceed 3.3 tons/ry

Note that the other pollutants at the permitted fuel consumption rate and hours of operation are below APEN de minimis and therefore were not included in the permit. However, emissions of these pollutants shall still be reported on any APENs submitted and are still subject to annual fees.

APEN reporting (condition 14 and Colorado Regulation No. 3, Part A Section II.C)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

Although not specifically identified in the construction permit, the gas heater is subject to the following applicable requirements:

• Particulate matter emissions shall not exceed PE = 0.5(FI)<sup>-0.26</sup> (Reg 1, Section III.A.1.b):

Where: PE = Particulate emissions in lbs/mmBtu

FI = Fuel input in mmBtu/hr

At the maximum heat rate of the heater, the particulate matter limit is 0.288 lbs/mmBtu. Since this is the most conservative limit, this value will be included in the permit.

 Regulation No. 6 – standards of performance for New Stationary Sources, Part B - Specific Facilities and Sources, Non-Federal NSPS, II – Standards of Performance for New Fuel-Burning Equipment, State-only requirements as follows:

o Particulate matter emissions shall not exceed 20% opacity

Particulate matter emissions shall not exceed PE = 0.5(FI)<sup>-0.26</sup> (Section II.C.2)

Where: PE = Particulate emissions in lbs/mmBtu

FI = Fuel input in mmBtu/hr

 Regulation No. 6 – standards of performance for New Stationary Sources, Part B - Specific Facilities and Sources, Non-Federal NSPS, I. – General Provisions, State-only requirements as follows:

- o Circumvention (40 CFR Part 60 § 60.12, as adopted by reference in Colorado Regulation No. 6, Part B, Section I.A)
- Good Practices (40 CFR Part 60 § 60.11(d), as adopted by reference in Colorado Regulation No. 6, Part B, Section I.A

# Streamlining of Applicable Requirements

### Opacity

The gas heater is subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for startup. The Reg 1 20% opacity requirement applies at all times, except for startup under which the Reg 1 30% opacity requirement applies. The gas heater is also subject to the state-only Reg 6, Part B 20% opacity requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. Therefore since the Reg 1 20/30% opacity requirements are more stringent that the Reg 6, Part B opacity requirement, the Reg 6 Part B 20% opacity requirement will be streamlined out of the permit.

## PM

The boilers are subject to the Reg 1 particulate matter requirements and the state-only, Reg 6, Part B particulate matter requirements. The particulate matter requirements in both Reg 1 and Reg 6, Part B are the same standard. The Reg 1 particulate matter requirements apply at all times. As indicated under the particulate matter streamlining section for the turbines the Reg 6, Part B particulate matter requirements are not

applicable during startup, shutdown and malfunction. As a result, the Reg 6, Part B particulate matter requirements have been streamlined out of the permit.

**2. Emission Factors-** Approval of emission factors is necessary to monitor compliance with the emission limitations. The source will be required to use the following emission factors (from AP-42, Section 1.4-1, dated March 1998 for boilers < 100 mmBtu/hr) to monitor compliance with the emission limitations:

Pollutant	Emission Factor		
NO <sub>X</sub>	100 lbs/mmSCF		
CO	84 lbs/mmSCF		

- **3. Monitoring Plan-** The source will be required to record fuel consumption and calculate emissions monthly to monitor compliance with the annual fuel consumption and emission limitations. Compliance with the PM and opacity requirements are presumed, in the absence of credible evidence to the contrary whenever natural gas is used as fuel in the boiler.
- **4. Compliance Status-** In their Title V permit application, the source indicated that the gas heater was in compliance with all applicable requirements. The Division agrees with this assessment.

# IV. Insignificant Activities

General categories of insignificant activities at this site include: fuel (gaseous) burning equipment < 5 mmBtu/hr, chemical storage tanks/containers < 500 gal or storage areas < 5,000 gal, landscaping and site housekeeping equipment (< 10 hp), lube oil storage tanks (< 40,000 gal), fuel (gaseous) burning equipment < 10 mmBtu/hr (for heating), and source with emissions below APEN de minimis levels. The following list of insignificant activities was provided by the source in their Title V operating permit application:

<u>Units with emissions less than APEN de minimis - criteria and non criteria pollutants</u> (Reg 3, part C.II.E.3.a & b)

Evaporation cooler drain basin (normally empty)

Seal oil pit #1 (normally empty)

Seal oil pit #2 (normally empty)

Used oil sump (normally empty)

Welding, soldering and brazing operations using no lead-based compounds (Reg 3 Part C.II.E.3.r)

Maintenance Shop

Chemical storage tanks or containers < 500 gal (Reg 3 Part C.II.E.3.n)

Oil storage (55-gal drums)

Mineral Spirits Storage (55 gal drums)
Full Force Anti-Freeze and Coolant Storage (55 gal drums)

Chemical Storage Areas < 5,000 gal capacity (Reg 3, Part C.II.E.3.mm)

Emissions of air pollutants which are not criteria or non-criteria reportable pollutants (Reg 3 Part C.II.E.3.00)

Raw water storage (200,000 gal) Treated water storage (200,000 gal) CO<sub>2</sub> purging

Lube oil storage tanks < 40,000 gal (Reg 3, Part C.II.E.3.aaa)

Lube Oil Storage #1 (3,600 gal) Lube Oil Storage #2 (3,600 gal)

<u>Fuel storage and dispensing equipment in ozone attainment areas throughput < 400 gal/day averaged over 30 days (Reg 3 Part C.II.E.3.ccc)</u>

Gasoline Tank, Unleaded (500 gal)

Storage tanks with annual throughput less than 400,000 gal/yr and meeting content specifications (Reg 3 Part C.II.E.3.fff)

Diesel Storage Tank, inside services building (above ground 250 gal)
Diesel Storage Tank, at drum storage area (500 gal)
Diesel Storage Tank, fuel holding tank for diesel generator (above ground 2,000 gal)
Diesel Fuel Tank, day tank for diesel generator (275 gal)
Oil/Water Separator

Stationary Internal Combustion Engines - limited hours or size (Reg 3 Part C.II.E.3.xxx)

Emergency Fire Water Pump (< 260 hp)

#### Not sources of emissions

Five (5) compressed H<sub>2</sub> bullets (H<sub>2</sub> used for cooling of generators)

Two (2) LP CO<sub>2</sub> tanks

Two (2) HP CO<sub>2</sub> tanks

Transformer TT11 (mineral oil, 11,715 gal) – closed loop system

Transformer TT12 (mineral oil, 11,715 gal) – closed loop system

Transformer auxiliary (mineral oil, 7,452 gal) – closed loop system

Glycol system #1 – closed loop system

Glycol system #2 – closed loop system

## V. Alternative Operating Scenarios

No alternative operating scenarios were requested for this facility.

#### VI. Permit Shield

The source did not identify any non-applicable requirements for inclusion in the permit shield.

The following applicable requirements were streamlined out of the permit and have been included in the permit shield.

For the combustion turbines:

- **State-only** 0.35 lbs/mmBtu SO<sub>2</sub> requirement (Reg 6, Part B, Section II.D.3.b), streamlined out since Reg 1 SO<sub>2</sub> requirement is more stringent.
- 114 ppmvd NO<sub>X</sub> at 15% O<sub>2</sub> requirement for the turbines (Colorado Construction Permit 99MR0169 PSD and 40 CFR Part 60 Subpart GG § 60.334(b), as adopted by reference in Colorado Regulation No. 6, Part A), streamlined out since the NO<sub>X</sub> BACT limit (15/25 ppmvd at 15% O<sub>2</sub>) is more stringent. Note this also includes the exemptions from the standard in 40 CFR Part 60 Subpart GG §§ 60. 60.332(f) & (i).
- Monitor sulfur and nitrogen content of fuel (40 CFR Part 60 Subpart GG § 60.334(b)) and test methods and procedures for fuel sampling (40 CFR Part 60 Subpart GG §§ 60.335(d) & (e)), streamlined out in favor of the continuous emission monitor (nitrogen sampling) and the Acid Rain requirement for pipeline quality natural gas (sulfur sampling).
- Excess emission reporting for any one-hour period during which the average water-to fuel ratio is less that the ratio determined by the performance test and/or any period nitrogen content is greater than that used in the performance test (40 CFR Part 60 Subpart GG § 60.334(c)(1)), streamlined out in favor of reporting excess NO<sub>X</sub> emissions determined by the continuous emission monitoring system.
- Excess emission reporting for any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 % (40 CFR Part 60 Subpart GG § 60.334(c)(2)), streamlined out in favor of the Acid Rain requirement for pipeline quality natural gas.

# For the gas heater:

- **State-only** particulate matter (0.5(FI)<sup>-0.26</sup>) requirement (Reg 6, Part B, Section II.C.2), streamlined out since Reg 1 particulate matter requirement is more stringent.
- State-only opacity requirement (20%) (Reg 6, Part B, Section II.C.3), streamlined out since Reg 1 20%/30% opacity requirement is more stringent.

## VII. Acid Rain Provisions:

Both turbines are affected units under the Acid Rain Program which is governed by 40

CFR Parts 72, 73, 75, 76, 77 and 78 and as such the source is required to have provisions for the Acid Rain requirements in its Title V permit. Units subject to the Acid Rain requirements are required to hold adequate  $SO_2$  allowances and have  $NO_X$  limitations. This facility is not listed under 40 CFR 73.10(b)(2) and therefore must obtain  $SO_2$  allowances as needed. Since these units are not coal-fired boilers, they do not have any  $NO_X$  limitations under the Acid Rain Program.

Typically, units subject to the Acid Rain requirements are required to continuously measure and record emissions of  $SO_2$ ,  $NO_X$  (with diluent monitor either  $CO_2$  or  $O_2$ ) and  $CO_2$  as well as opacity and volumetric flow in accordance with the requirements in 40 CFR Part 75. Since these units burn natural gas, these units are not required to have a continuous opacity monitor and can use an alternate monitoring method (Appendix D), in lieu of installing and operating a continuous emission monitor for  $SO_2$ .